

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Investigation by the Department of Telecommunications and Energy on its own motion, pursuant to G.L. c. 164 §§ 76, 94 and 94A, to investigate the appropriateness of the use of Risk-Management Techniques to Mitigate Natural Gas Price Volatility

D.T.E. 01-100

COMMENTS OF THE ATTORNEY GENERAL

I. INTRODUCTION

On December 4, 2001, the Department of Telecommunications and Energy (“DTE” or “Department”) issued an order opening a Notice of Inquiry into the Appropriateness of the use of risk-management techniques to mitigate natural gas price volatility. *Risk-Management NOI*, D.T.E. 01-100 (2001). On the same day, the Department requested comments from interested parties regarding the structure of a potential risk-management protocol for Massachusetts local distribution business companies (“LDCs”). The Department also requested comments on nine specific questions regarding risk management. The Attorney General provides his comments and his responses to the nine questions as requested by the Department.

The Attorney General strongly recommends that the Department prohibit gas distribution companies from using financial or commodity derivatives to “hedge” the cost of gas that they provide to their customers. Allowing companies to use customer funds to buy these derivatives

is fraught with dangers for customers and the utilities. The market place is strewn with bankruptcies and other business failures of derivatives trading firms that are much larger and more experienced than the gas distribution companies in the Commonwealth. Neither the utilities, customers, nor regulators are ready to analyze and evaluate the prudence of transactions in derivatives. Ultimately, allowing companies to speculate in the derivatives markets will increase the financial risks for the companies and increase costs for their customers. The evaluation, management and burdens of the risks associated with these derivatives should be left to the players in the competitive marketplace who have far greater capacity to perform them.

II. DISCUSSION

The gas distribution companies in the Commonwealth collect the cost of their gas supplies through the Cost of Gas Adjustment Clause (“CGAC”). The CGAC allows utilities to recover all of their prudently incurred gas supply costs. This mechanism effectively passes on all of the risk associated with the volatility of the price of gas from the utility to its customers. The Department’s Notice of Inquiry raises many issues that are discussed below.

A. Several Mechanisms Exist That Mitigate Gas Price Volatility For Customers

Natural gas distribution customers in the Commonwealth already have available to them several mechanisms that mitigate the volatility of the price of gas that is flowed through the CGAC:

- a forecast CGAC for a six-month period that smooths out expected fluctuations during that period;
- a year-end reconciliation that normally carries over any under- or over-recovery to the next season;
- the availability of levelized billing plans which equalize monthly payments throughout the year; and
- physical hedging, including filling storage with gas during the off-peak periods when gas costs are lower.

These various mechanisms provide customers with a substantial amount of price mitigation, with the levelized billing providing the maximum protection. Therefore, the use of derivatives to mitigate price volatility is to a great extent redundant of these existing mechanisms.

B. The Commodity and Derivatives Markets

Gas purchasers have available many mechanisms to mitigate the price volatility of their gas supply. These mechanisms can be broken into two main categories, physical hedging and financial hedging. Physical hedging relates to swaps and actually storing gas during periods of low demand when it is expected to be cheaper in price and using that stored gas during periods of high demand when it is expected that prices will be higher. Most gas utilities use physical hedging to some extent. Financial hedging relates to using financial securities and contracts that are derived from the underlying gas commodities prices. With these financial instruments, a gas purchaser can lock prices or price ranges of gas for a certain period. It can speculate and profit on price increases or price decreases.

The commodity market for natural gas in the United States is large and robust. The gas derivatives market is equally efficient. Ultimately, like any efficient market, positions that “beat the market” should be short-lived as the other players in the market learn and arbitrage those advantages away. Therefore, the Department can expect that any attempt to systematically “beat the market” through the use of hedging techniques will fail and only end up costing customers money due to the transaction costs if not the losses on the trades themselves.

The Department will have to understand, audit and analyze all of the different hedging mechanisms and techniques used by and available to the LDCs in order to determine the prudence of the costs that the LDCs will seek to recover. The list of hedging mechanisms is long and growing every day as the markets create new and different ways to manage risk. The effort and cost of a complete regulatory review of these hedging programs will be large and ever expanding.

C. The Costs of Price Volatility Management Will Outweigh Any Benefits

There has been no showing that new hedging mechanisms will provide any net benefits to customers. Certain parties have argued that gas customers might benefit from new hedging mechanisms that might possibly reduce price volatility and even lower gas costs when the utilities gamble and beat the market. However, they have not shown that new hedging will have a *net* benefit to customers. Indeed, they fail to address the costs of these new hedging techniques and they fail to compare those costs to the benefits to show that customers, in the end, will actually enjoy a net benefit from these new programs.

The Department should not approve any new utility activity without a definite showing of net benefits to customers. The Department must determine that the rates that a gas company charges are “just and reasonable.” As part of that determination, the Department reviews the costs of providing the regulated service to determine whether they were prudently incurred and whether they were necessary to provide utility service to customers.

The Department has also found that a utility’s investments should also provide benefits to customers. Whether those investments are in utility plant or investments in utility stock, utilities have always been required to show that the benefits outweigh or at least equal the costs. Furthermore, the utilities have the burden of proof to make the showing that the costs associated with these investments exceed the benefits. Without such a showing, the Department should deny the recovery of any costs related to those investments.

D. A Price Volatility Program That Uses Derivatives Will Increase The Cost Of Service To Gas Customers

Any price volatility program that is proposed by the utilities will necessarily come with some new incremental costs. These costs will include the following:

- an increased cost of capital as the utility puts its assets and earnings at greater risk due to speculation in the derivative securities markets;
- new transaction costs associated with the firms performing the actual trading of the derivative securities;
- new company employees and consultants to manage, facilitate, and carry out trading activities;¹
- new computers, and computer software to support the trading activities;
- new accounting and auditing costs;
- new Department employees to analyze and oversee the prudence of this new activity; and
- other regulatory costs associated with the regulatory proceedings, including legal fees, transcript costs, copying costs, expert witnesses, and filing fees.

Any hedging technique that the utilities may introduce will come with significant costs that in some cases are easy to measure (e.g. employee salaries and computer software), but in others, are not so easily measurable (e.g. increased cost of capital). In either instance, however, those costs must be included in the cost benefit analysis of any hedging program.

¹ It should be noted that some of the distribution companies have downsized their gas purchasing divisions after their rates were unbundled, since they expected competitive gas suppliers would be transitioning customers off the system. Now, the utility would have to hire new employees to begin the process of understanding, designing, training and implementing a derivatives trading operation.

E. The Inclusion Of Hedging Costs In The CGAC Will Unnecessarily Expose Gas Customers To Speculative Investments

From the customers' point of view, the use of derivatives to hedge gas costs is nothing more than a gamble with their money. It is a gamble that efficient markets will not let the customers systematically win over time.² Therefore, customers should not expect the utilities to "beat the market" with derivatives. They should only expect to incur higher costs as a result of incurring administrative and transaction costs associated with the trading and the regulatory oversight of those activities.

The inclusion of hedging costs in the CGAC will burden gas customers with the risks of the utilities' speculation. Assuming the gas and the derivative markets are efficient, there is little chance that the utilities will systematically beat the market. Therefore, the transaction costs by themselves will cause customers to see a net cost to any hedging mechanism over time.

The past two winters provide a good example of how customers can win or lose. Customers may have saved money if utilities had used derivatives to "lock-in" 2000-2001 heating season prices during the summer of 2000. However, had similar derivatives been used to "lock-in" the 2001-2002 heating season prices during the summer of 2001, customers would have lost a lot of money as compared to the index values.

F. The Department Should Reject The Use Of Derivative Securities Because Of The Possibility Of Huge Losses On Securities Trading

The business world is strewn with the bodies of derivative trading firms that have been

² It should be remembered that for every buyer of a security there is a seller. For every winner there is a loser. Customers cannot expect to win every time.

bankrupt or nearly bankrupt by their hedging and hedging related activities. These companies, including Enron, Long Term Capital Management, Kidder Peabody, Barings, and Sumitomo Bank had expertise that far exceeds that of the utilities, yet still incurred billions of dollars in losses.³ Some have even gone bankrupt as a result of their bets that have gone wrong.⁴ If these firms failed at hedging in the markets, there is no reason to believe that a gas distribution company in Massachusetts should be able to perform any better.

G. The Introduction of New Gas Supply Products and Services Well Stifle the Competitive Market That The Department Is Trying To Create

The Legislature and the Department have both made great efforts to open the utilities' natural gas supply business to competition. The initiatives include unbundling of rates; providing for third party gas supply management, billing and metering; reducing gas supply contract lives; initiating competitive supplier pilot projects; and educating customers about the market for competitive supplies. However, the competitive market, although having reached some of the largest customers, has failed to have broad impact on small users whether they are residential or business customers.

The Department should not stifle the creation of competition in this nascent market by creating new regulated products that can and should be provided in the competitive market. Gas

³ Bankruptcies happened even with the advice of Nobel Prize winners like that of Myron Scholes who derived some of the fundamental theories of the derivative markets. Mr. Scholes was one of the principals of Long Term Asset Management, a hedge fund that rocked the markets when it almost went bankrupt, only to be saved by the direct intervention of the Federal Reserve.

⁴ Of course, there are other cases like Orange County Investment Pool where the failure resulted from the pure lack of expertise in the derivatives market.

services with fixed prices, capped prices or any of the plethora of pricing variations, created with or without hedging techniques, should be provided by the competitive market. The competitive market is the appropriate vehicle for these products, since its players will have the expertise to market and price these products and the financial expertise breadth and depth to analyze and trade any underlying derivative products. Ultimately, the significant risks associated with any hedging should be borne by the players in the marketplace who are much better suited to evaluate and manage those risks than the utilities.⁵

III. SUMMARY AND RECOMMENDATION

For all of these reasons, the Attorney General strongly recommends that the Department not allow any new hedging techniques proposed by the gas distribution utility companies. These speculative techniques expose customers to risk without any guarantee of long-run net benefits.

⁵ If the Department finds that utilities should provide some new type of hedging to reduce price volatility, it should only allow them to provide such a service through an unregulated affiliate that provides the service as a competitive offering that is separate and distinct from the existing CGAC recovered gas supply service provided by the regulated utility company. Furthermore, that new service offering should have many clear warnings that indicate its inherent risks, before a customer takes such service.

Question 1: Should Massachusetts gas utilities be allowed or required to implement a risk-management program to mitigate price volatility for gas customers?

Response: No. Massachusetts gas utilities should not be allowed or required to implement any new risk-management programs to mitigate price volatility for gas customers. There are several reasons why gas utilities should not be allowed to implement any new risk-management programs.

First, Massachusetts gas customers already have several mechanisms in place that mitigate price volatility. These volatility mitigation mechanisms include:

- (1) a six-month forecast Cost of Gas Adjustment Clause mechanism to recover gas supply costs that smooths out the typical peak period price spikes;
- (2) an annual reconciliation of over and under collections of gas costs from the previous, with recovery over the next twelve months;
- (3) levelized billing plans; and
- (4) physical hedging including off-peak injection of storage for the peak period..

Second, the introduction of new gas supply products by the gas distribution utilities will stifle competition in the competitive supply market.

Third, the gas distribution companies in Massachusetts do not have the capacity to evaluate and manage the risk associated with new risk management mechanisms, especially derivative securities.

Fourth, many of the new risk management mechanisms will put the utility at great financial risk, a risk that is neither prudent nor in the interest of customers.

Fifth, there is a high probability that the cost of the new risk management mechanisms will exceed the benefits in the long run, so customer will not benefit from new programs.

Please see the Attorney General's Comments for a more detailed discussion of each of these topics.

Question 2: How will risk-management by LDCs affect gas unbundling and customer choice in Massachusetts?

Response: New risk management mechanisms by Local Distribution Companies (“LDCs”) will stifle competition in the gas supply market and effectively reduce customer choice for different suppliers in that market. The Department has made a serious attempt to open the gas supply business to the competitive market since the introduction of a competitive supply pilot project with Bay State Gas Company in 1996. However, since that time, although some large customers have available and are using competitive suppliers, the vast majority of gas distribution customers in the Commonwealth do not have any choice. Having the LDC introduce new gas supply products at this time may deter new entrants from entering the market.

The Department should determine, in a public venue, whether there will be any competitive options available to all customers in the future or whether the LDC will be the sole provider of service for customers, before allowing LDCs to provide such a service. If the Department determines that the market place has failed and that the LDCs are the only viable providers of the service, then it should assess the individual LDCs ability to offer a variety of gas service options (fixed-price, capped price, etc.) and how these new options should be structured, what specific resources should be in place, what customer education must be done and over what time line the program should be put in place.

Question 3: Should gas utilities be limited to specific types of risk-management instruments? If so, what types?

Response: Yes. Gas utilities should be limited to those risk management instruments that they are already using to provide gas supply service in the Commonwealth. Introducing new instruments will increase the costs for customers with no long-run net benefits and it will increase the need for regulatory oversight and drive up regulatory cost. An incentive mechanism will encourage the utility to engage in greater financial risk in an effort to reap greater gains for its shareholders, but may result in losses and catastrophic financial events that might bankrupt the utility.

Furthermore, the Department should assess what the utilities are doing currently and the adequacy of current levels of resources being employed in each of the LDCs gas procurement programs. Because the DTE has no stated policy or set of regulations regarding hedging, it is not clear what hedging activities each utility is currently engaged in. An assessment of the current practices is a logical first step in the Department's investigation of whether to allow Company's to mitigate gas prices in any way.

Question 4: Should there be a percentage volume of gas that LDCs would be allowed to hedge?

Response: The LDCs should not be allowed to do any more hedging of prices than it already does. See also the Attorney General's Response to Question 1.

Question 5: What should the core objectives of a hedging program be (e.g., least cost, price stability)?

Response: The core objectives of a hedging program should be a stable, low cost gas supply at minimal risk. However, since the Department has indicated its strong desire to open the gas supply service to the competitive market place, all new services with these new hedging programs should be provided by those suppliers in the competitive market, since the market place is better able to meet those core objectives.

Question 6: How will the Department assess risk-management programs? What benchmarks should be used to measure a risk-management program's performance?

Response: The Attorney General recommends that all new hedging and risk-management programs be limited to the competitive market place. Therefore, the Department will not have to assess or measure the management programs and their performance. This proposal will save the Department, the utilities, and their customers time, effort, and money.

Question 7: What standard of review should the Department apply to the utilities' initial risk-management program?

Response: The Department will have to do full prudence reviews of the hedging programs to ensure that the costs proposed for recovery through the Cost of Gas Adjustment Clause (or whatever new charge is used) are necessary and reasonable for providing gas service. Thus, similar to the Generating Unit Performance prudence reviews that the Department performed to audit the prudence of electric utilities management and operations of their generating plants, the Department will have to conduct similar proceedings to audit the prudence of the gas supply hedging programs of the gas utilities. This type of oversight and regulation of the energy supply is one that the Department moved away from in the electric industry. Introducing hedging programs will only work in the opposite direction of lessening regulatory oversight, causing the need for more regulation and more oversight.

Question 8: What types of costs are associated with risk-management? Should LDCs be allowed to recover these costs? If so, please explain how.

Response: Any price volatility program that is proposed by the utilities will necessarily come with new incremental costs. These costs will include the following:

- an increased cost of capital as the utility puts its assets and earnings at greater risk due to the new venture into speculating in the derivative securities markets;
- new transaction costs associated with the firms performing the actual trading of the derivative securities on the boards;
- new company employees and consultants to manage, facilitate, and carry out trading activities;
- new computers, and computer software to support the trading activities;
- new accounting and auditing costs;
- new Department employees to analyze and oversee the prudence of this new activity; and
- other regulatory costs associated with the regulatory proceedings including legal fees, transcript costs, copying costs, expert witnesses, and filing fees.

The Department should not allow the LDCs to initiate new hedging programs, and therefore it should not allow the recovery of any of these costs. However, if the Department were to allow some new program, it should only allow utilities to recover these costs on a year to year basis, if they can show that in each year there were quantifiable benefits as a result of the incurrence of those costs that exceed the quantified program costs for that year.

Question 9: Should an incentive mechanism be used in conjunction with a risk-management program? If so, please explain how this mechanism should be structured.

Response: No. An “incentive mechanism” should not be used in conjunction with a risk-management program involving the use of derivatives. The Department should not allow any “incentive mechanism” due, among other reasons to the possibility (and arguably the probability) that there will be some significant financial loss as the result of trading derivatives in a incentive mechanism. Even though the Department might limit the risk for customers, the fact that the utility may face large losses that would leave it crippled financially and unable to safely perform its basic gas transportation obligations means that the Department may still have a serious problem that it must deal with to ensure the utility service continues.

Sincerely,

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